STATE OF CALIFORNIA

ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In Support of the 1999 Natural Gas Price and Supply Forecast	)	
	)	Docket No. 99-FR-1

HEARING of the

FUELS and TRANSPORTATION COMMITTEE

Friday, January 11, 1999

10:00 a.m.

Held at the:

California Energy Commission
1516 Ninth Street, Hearing Room A
Sacramento, California 95814

Reported by: George Palmer

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MICHAL MOORE, Associate Member (not present)

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(Alphabetically listed)

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LEON BRATHWAITE

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I N D E X

Friday, January 11, 1999 10:10 o'clock a.m.

P R O C E E D I N G S

PRESIDING COMMISSIONER SHARPLESS: Good morning. I would like to welcome you to the Fuels and Transportation Committee Hearing on natural gas. I am Jan Sharpless, and I am the Presiding Member of this Committee.

Michal Moore, who is the Associate Member, will not be able to be with us today. But his Assistant, Susan Bakker, is here to my left. And to my right is Rosella Shapiro, my Advisor.

I will introduce the Staff a little bit later on. But I would like to begin by discussing what the purpose of today's meeting is. We will be discussing issues related to the natural gas market and Staff assumptions that will be used in generating the 1999 Natural Gas Price and Supply Forecast.

This Hearing is being conducted to provide part of the record for the Energy Commission's 1999 Fuels Report. And although the 1997 Fuels Report has not yet been adopted by the Commission, the Fuels Committee did not want to delay the timely production of the Natural Gas Price and Supply Forecast for the next round.

We expect the Commission to be adopting the 1997 Fuels Report shortly, once the policies related to methyl tertiary butyl ethers have been resolved. In the meantime we will be proceeding with the record for the 1999 Natural Gas

Forecast.

As part of the Warren-Alquist provisions, the Commission has over the years developed energy supply and price forecasts and analyzed market trends to provide information on how the energy market has been changing and where we are headed in the future.

The Energy Commission is now in the process of preparing the 1999 Natural Gas Price and Supply Forecast. In the future we anticipate generating this Forecast on an annual basis as opposed to the biennial basis used in the past. The driving force behind this change is the fact that using a two-year process renders a forecast using very old, underlying information.

As you are all aware, the market is getting more competitive and consumers want and need more choice. Suppliers and transporters have more competitive options today. And all market participants need information that is up-to-date and addresses current market conditions.

With this in mind, it is anticipated that generating this forecast on an annual basis will provide the industry and decisionmakers with objective information that can be relied upon in making decisions and choices with regard to the fuels used in the state.

Natural gas is a premium fuel. It is a clean-burning fuel and is available in abundance. Looking at recent

forecasts developed by a variety of sources, natural gas, wellhead price, growth rates throughout the U.S. and Canada are expected to be relatively moderate. The Commission's forecast adopted in March of 1998 attests to this observation.

During this hearing the Commission Staff will present assumptions that will be used in generating a base or reference case for continent-wide wellhead prices and supplies and end-use price forecasts for each market sector within the state.

This base case will provide a foundation for Staff's 1999 forecast of prices for California consumers, including power generators, industrial, commercial and residential users over the next 20 years. Staff will also present the changes being made to the NARG model structure. Specifically, they will discuss the new pipelines to be added in the base case and changes made to represent the end-use sectors in the model.

Today we will also hear from one expert witness, Scott Stevens of Advanced Research International, on unconventional sources of natural gas available in the U.S. He will provide testimony that is essential to better understanding some of the fundamental assumptions underlying the Forecast. His testimony will cover the reserve estimates, production and forecast from unconventional gas resources in the United States.

Before starting with Staff presentations, I have a few sort of housekeeping details. If any of you are interested in making a presentation or commenting today, I would ask you to please fill out a blue card. They are out in the front there by the front door and give it to the Staff at the Staff table who will bring it forward. That way we will know who wishes to speak today.

The Committee Hearing is also being recorded. And we would like to conduct this hearing particularly informally with each presentation or testimony followed by discussion.

If you are making comments, we would ask you to please come forward and use the microphone to be part of the record and at that time to please give your name and your affiliation.

If anyone needs special accommodations and scheduling your presentation at this Hearing, please note that also on your blue cards.

With that, I would like to sort of go over the Agenda before we start with the Staff presentations. We'd like to start today with an overview by Jairam Gopal. Then we will have a presentation on resource estimates by Scott Stevens and Scott Tomashefsky; discount rates by Leon Brathwaite; end-use price forecast issues by Bill Wood. And then comments from parties and any concluding comments, and then we will adjourn.

So that will comprise our Agenda today. I am looking

forward to the discussion and appreciate the attendance here this morning by those of you who have an interest.

So we will start with Mr. Gopal. Would you like to begin?

MR. GOPAL: Commissioner Sharpless.

PRESIDING COMMISSIONER SHARPLESS: Perhaps you could also introduce the Staff at the table for those who are in the audience.

MR. GOPAL: Before I start, as the Commissioner said, we will be having several presentations by Scott Stevens, Scott Tomashefsky. Leon Brathwaite will be joining us very shortly, and Bill Wood. And I will introduce them at the appropriate time.

To start with, we adopted the previous Forecast in March of '98. And we have been planning on doing the Natural Gas Forecast on an annual basis as compared to the biennial we practiced in the past. Hopefully this will provide current and recent information to all decisionmakers and industrial participants.

Today the things I will be doing are to define and review assumptions for the next Forecast, define and review of methodologies for the End-Use Price Forecast. I would also like to receive input from different parties on relevant issues that should be considered. Basically we are looking at impact of regulatory and policy changes, impact of electricity

restructuring, which is an ongoing and continuing proceeding, also at pipelines which are supplying the natural gas to California. We will discuss some of those issues.

I will provide the general overview and assumptions that form the Forecast. We will then go into three different topics specifically arranged for today. We will talk about resources, discount rates and end-use price issues.

For those who are not very accustomed to the NARG or the North American Regional Gas Model, this slide shows a very brief summary of how it works. Basically it is a dynamic model. And it looks at different time periods in different regions concurrently. And the model then generates long-term equilibrium prices and gas flows.

The major inputs to the model include resources curves, core gas demand, oil price forecasts and alternative fuel price forecasts, infrastructure which consists of the interstate and intrastate transportation costs, capacities and intrastate utility distribution rates and finally the noncore energy demand which consists of most of the industrial and power generation markets. And in the power generation, we include the electricity generation and coal generation together.

Major outputs from the model include gas production by region and by technology, gas consumption by region and customer class, and finally we obtain wellhead gas prices as

well as the citygate and burner-tip.

Looking at the complexity of the model, this diagram just represents how the model is structured. You have supply regions indicated by the large oval sections. And finally we have the demands, which are the small circles. Supply and demand are all interconnected by pipeline corridors. They could be individual pipelines or a combination of several pipelines which take gas from one point to the other.

The model also includes the potential to consider inputs of LNG at various terminals currently which are operating mostly on the East Coast.

Again, this model considers supply and demand regions in Canada, U.S. and to some extent even Mexico. We do not include the supply detail we have for the U.S. and Canada for Mexico.

This slide shows the model structural changes we anticipate to make. Basically before going into the change, if you can look at the diagram on the right side, you have an allocation which presents the wholesale natural gas market and then you have bifurcation in the model which considers the core demand and the noncore demand.

By definition, core is the market which depends solely on natural gas, whereas the noncore market represents those customers who have the capability to either use alternative fuels or they can curtail themselves from use of

natural gas at specific times.

The change we want to look at is to split noncore into two nodes, basically to address the industrial demand, and the second one to address the electricity generation.

Separating the electricity generation has several benefits. One is we can actually look at how the power generation demand is going to change in the U.S. We can address the growth rates for power generations separate from the industrial. And also will be able to, with this change, reflect alternative fuel capability in the industrial and power generation. Maybe we want to put some alternative fuel price which is equivalent to diesel or heavy fuel oil for some regions, but we may need coal prices in the others. So we will certainly have this capability with this change.

So once these changes are made, and actually they have been done, and we have just tested the model to make sure it works, the next slide shows the changes. And basically you can see -- this was the old sector we had. And when we changed it, we had the power generation demand here. So we are able to separate the two. We will be able to consider the differences in transportation rates in addition to the capacities.

This slide shows current structure of gas imports into California. Basically we have three major import points into the state. The PGT system on the north, Kern River

coming in between and El Paso and Transwestern, which are coming in the south end of the state.

From El Paso and Transwestern, of course, we have the Mojave which comes and joins the Kern River inside. Bill Wood will be later on talking about some of the changes that will be made or that we are considering in this pipeline issue.

One thing we will be doing for the U.S. as a whole is to add the Alliance Pipeline which is designed to transport natural gas from Alberta and the B.C. region directly to the Chicago demand area.

This pipeline has been in the books for some time. And during the last forecast we looked at this from a sensitivity point of view. We have analyzed the potential changes that can happen if the pipeline is built. The pipeline has got the approval from the FERC as well as the NEB now. And I think it has a green light to be constructed. So we intend to include this in our base-case analysis.

We will certainly be making changes to the transportation rates and capacities as specified today. So we will get the current information for that.

Basically I think as far as California is concerned, it does impact some changes. We will see a very moderate change in price for Canadian gas that comes directly to California.

The other broad trends that could change are with the

increased flow of Canadian gas into the Chicago area, it may suppress some of the Gulf Coast gas that goes up, thereby increasing the competition for Gulf Coast gas that comes into California. We can certainly provide additional information to anyone who is interested later on.

The second bullet here on this slide is regarding the changes in the pipeline system within California, the potential for Kern River and Questar Pipelines to be operating within the state. Bill Wood will address this issue later on.

I will briefly go over the different assumptions we will be making in this forecast. Basically the demand projections which we have always obtained from GRI's baseline projections, we will continue with that trend and we will be incorporating the 1999 baseline projections which have just been released.

We haven't got the full series and the data book yet, but it's on order. There are some changes. They expect natural gas demand to rise to 32 trillion cubic feet per year by the end of our forecast horizon around 2015. That is probably a little larger than what we had in the previous forecasts. So we will look at the implications of this change.

For Canada, the demand projections will be obtained from NEB. That's the National Energy Board or Canadian Gas Association. For California, we will be using the demand

projections which have been published in 1998. We will certainly consider any changes that could be made or impacts of restructuring. Electricity restructuring on natural gas demand in California will be incorporated. And these will be spelled out when the forecast is provided for review.

We will also be updating the interstate pipeline transportation capacities and rates. And we are also planning on reviewing our assumptions for distribution rates. And this is important because we are trying to split the electricity demand out of the industrial and we need to identify how the differences will turn out.

This slide is a little early for the day, but I will show it and talk about it right now. We can certainly review some of the dates and things like that later on, depending on input.

First of all, we need to receive input from all the parties who have been participating in the fuel support process and the natural gas forecast process. Staff will then prepare the preliminary Natural Gas Price and Supply Forecast. We plan to hold a hearing or workshop around May 10th of this year. That is when we will look for review from all parties on the Staff Forecast.

May 11th and 12th we will be holding the North American Regional Gas Model User Group Meeting in Sacramento. Anyone interested, please call me.

We intend to adopt the Natural Gas Price Forecast proposed by the Committee around June 9th of this year. Of course, these dates are not cast in stone yet and will certainly depend on the level of interest and the changes we may have to make to the Forecasts over time and, of course, to a regulatory processes that can be impacting our process.

So that sort of concludes my very initial briefing, if there are any questions.

PRESIDING COMMISSIONER SHARPLESS: Are there any questions at this point from anybody who would like to raise them?

(No response.)

PRESIDING COMMISSIONER SHARPLESS: Fine. I think it was clear.

And we go to the next.

MR. GOPAL: I believe Questar has a blue card in, and they want to be heard before 12:00 o'clock, but we can certainly do that after the Resources.

PRESIDING COMMISSIONER SHARPLESS: Well, let me ask -- is it Mr. Greenwood?

MR. GREENWOOD: Yes, ma'am.

PRESIDING COMMISSIONER SHARPLESS: Would you like to go now or would you like to listen to some of the rest of the Staff's presentation. Would that be helpful to your presentation?

MR. GREENWOOD: I will be happy to listen to it. I would just request that I have an opportunity to speak before the 12:00 o'clock hour.

PRESIDING COMMISSIONER SHARPLESS: We will keep an eye on the clock.

MR. GREENWOOD: Okay. Thank you.

PRESIDING COMMISSIONER SHARPLESS: Thank you.

Why don't we go forward, then?

MR. GOPAL: So we will now have Scott Stevens from Advanced Resource International. He will be talking about unconventional natural gas resources in the U.S. And he will provide an update on the reserve estimates, the production capabilities and a forecast they have done inhouse on natural gas production prices of unconventional resources.

MR. STEVENS: Can everyone hear if I can speak from here, or do I need to --

PRESIDING COMMISSIONER SHARPLESS: Well, it's being recorded, so let me ask the recorder.

Can you hear him without the microphone?

(Comments off the record.)

PRESIDING COMMISSIONER SHARPLESS: For the purposes of the audience, if you could speak as loudly as possible without losing your voice that would be helpful.

MR. STEVENS: Well, thank you very much. It is a pleasure to be here. And I would like to thank the Energy

Commission particularly the Task Manager, Leon Brathwaite, for inviting me out here today.

The topic of my talk is what we call "Unconventional Natural Gas." And we put this in quotes because actually this is a term that was thought up several decades ago and now these so-called unconventional gas resources are becoming part of the mainstream of the natural gas supply in the United States.

And just a little word about my company, Advanced Resources International, ARI. We are a technical consultant company that works strictly in the upstream, exploration and production of natural gases. particularly unconventional gas resources. And so we have a fairly narrow focus. And we don't deal with it downstream. Once the gas is in the pipeline, basically that is out of our area. So I won't be able to answer any questions in that regard.

So a little bit about the scope of today's talk and the study. The Energy Commission requested we provide information on unconventional natural gas. And there are three main types. There is tight gas, which is low permeability sandstones. There is coalbed methane, which is methane gas produced directly from coal seams. And there's also gas shales which is gas produced from organic carbon-rich shales. And these are the three types of resources I will be talking about.

The period of time for the study is to provide updated information from '92 up to '97 for gas production and reserves from these resources to enter into the Energy Commission's model. And, in addition, we have used a model we have developed independently to forecast future production of unconventional gas in the United States out to the year 2020. So we will be covering these three main areas today.

I would like to just mention we have been working in this area for many years now, and we would like to cite some of the funding we have received over the years particularly from the Gas Research Institute. We have done a number of resource evaluations in coalbed methane, gas shale and tight gas basins throughout the United States for GRI.

The department of Energy, the United States DOE, particularly the Energy Information Administration, we have developed unconventional gas supply models for them. Most of the data actually comes from private client work in the areas of exploration and production, particularly reserve evaluation, technology applications. This gives us kind of the meat of our model, the end-use cost and resource information.

And then finally today we were very grateful we had a chance to update this information with the very latest data available for 1997 on production and reserves and also to reanalyze, reassess our information for the impact on

California's natural gas supply.

Now, unfortunately, there's no easy way to get this information. It really has to be dug out from a number of areas. The data for production of unconventional gas often is not very well reported. We do use petroleum information and Dwight's Databases which are commercial production databases.

We have information from the State Geological Surveys throughout the U.S. These basins exist all across the country, particularly in the Rockies and also in Appalachia and the mid-continent areas.

Then we have information that we have used from individual operators: cost information, production data, reserves, and so on. Of course, this is all protected as confidential data. But in the model it is not revealed by operator.

Now what are we really talking about here? Well, the diagram on the left shows a cross-section of a typical conventional natural gas reservoir. You can see it is an arched structure and a final structure. For example, you have a reservoir which is charged with gas. It is kept from leaking out by a seal on the top. And there's a source somewhere down below where the gas originally came from. This is conventional natural gas. And everyone in the industry is pretty familiar with this.

The flow rates tend to be pretty high initially. And

the challenge is really locating the structure and also quality high porosity and permeability reservoir or play.

Now in the United States, particularly on shore, these reservoirs have largely been discovered and we are down to relatively small and structurally complicated reservoirs. And this maturity in the United States has brought about a new type of resource. And that is this unconventional gas.

The gas is stored in a very different way, unconventional gas. It tends to be stored in very large formations. The formation itself acts as its own source, seal and reservoir.

So the gas doesn't really have to migrate anywhere. It doesn't have to be sealed usually. It is just the reservoir pressure itself which seals the gas.

But the challenge is finding good permeability. And permeability is the ability of the gas to flow through the reservoir to the well bore so it can produce an economic flow rate. And that is, indeed, a very big challenge. And the big breakthrough has been much better improvement in locating naturally fractured areas.

Now today the unconventional gas is becoming more and more important. In fact, every year its importance is increasing. And today it's all the way up to 23 percent of total natural gas production in the United States.

As you know, the U.S. produces about 19 Tcf. This is

1997 data. Unlike oil, we are largely self-sufficient in natural gas production. There are imports from Canada, but 90 percent of our gas is produced domestically. Twenty-three percent of this is unconventional. And most of the tight gas, about 2.9 Tcf. Coalbed methane a little over one Tcf or a trillion cubic feet. And the gas shale about .3 Tcf here.

The pie chart on the right shows the reserves. And actually conventional gas accounts for even a larger fraction of reserves. These are proven reserves. There are wells behind these numbers. This is not just resource in place. These are actually recoverable gas. Thirty-one percent of the total gas reserves in the United States is unconventional gas.

This is our history over the 1990s. And you can see that overall natural gas production has increased from about 2.7 Tcf back in 1990 up to nearly 4.5 Tcf in 1997.

The pink is the tight gas which has been fairly stable over this period. Really the growth has come from two resources: The yellow which represents coalbed methane. Methane produced in coal seams has increased dramatically. And also gas shale, in blue, has also increased quite a bit.

Now there was a very important tax credit which expired at the end of the year 1992. This tax credit was for unconventional natural gas resources. It gave operators a very power stimulus for investing and producing unconventional gas resources.

This entirely disappeared at the end of '92. At this time many observers in the industry felt these types of resources were going to suffer, production was going to go down, and investment was going to decline markedly.

And, as it turned out, the tax credit was very helpful in helping to stimulate R&D into new production and technologies. It largely helped the industry to stand on its own feet. And that's exactly what happened in the post-'92 period. And you can see production has increased by well over a Tcf in that period and it's still going up today.

Now some certain isolated resource plays were very strongly negatively affected by the tax credit going away, but other ones have come on to more than take its place.

And this is just along the same lines. It is just a little snapshot of one particular play. This is the Barnett Shale, which is gas shale, low-permeability shale in the Fort Worth basin of North Texas. And this play started out as largely a tax credit play, Section 29 tax credits here.

The operator was interested particularly in getting the benefit from these tax credits. And so the production increased to about 20 million cubic feet per day. That's the red line. And the number of wells on the right here, up to about a hundred wells total.

But then after the tax credit expired, drilling continued up to about 300 wells in 1997, and it is still

increasing very sharply. And the blue shows the production, total production. And the wedge between the blue and the red is all nonqualifying production. It is just entirely competing with conventional natural gas supplies.

And I don't, of course, have time to go into every play in America. There are dozens and dozens of them. But that's just a good example.

Now I will just very quickly go through each of the resource types. The tight gas, first. You can see there's a number of plays in the United States, a number of tight gas basins. Think of them perhaps as the Rocky Mountain Province here, the Gulf Coast and the mid-continent here, and then the Appalachian Basin there.

Of course, for California's perspective, the Rocky Mountains are by far the most important region for tight gas production. And I just would point out the San Juan Basin here, the Greater Green River Basin, the Permian Basin and also the some of the mid-continent areas like the Anadarko are very important to California.

Here is a listing of some of the important basins which are starred with the red star as being particularly important for California. And you can see that the San Juan Basin contributed nearly half of a Tcf of production in 1997 with eight Tcf of reserves left.

The Green River Basin, the 400 Bcf; other Rocky

Mountain areas, 250; and then the Anadarko-Permian here we have over a half of Tcf. So these are very important resource areas for California.

Just a review of the coalbed methane basins. This is the second of the three unconventional resource types. Coalbed methane got its start in a basin here in Alabama, the green-colored Black Warrior Basin, and also in the San Juan Basin which is very important for California in Northern New Mexico, Southern Colorado. These are the two main producing areas for coalbed methane today. And they are shown in green because they are the established, mature areas. They are largely drilled up.

Now the red areas are some of the emerging areas. Originally there was thought that was all there was going to be. But, in fact, after the tax credit, the Raton Basin here in New Mexico and Colorado, the Uinta Basin in Utah, the Powder River Basin in Northern Wyoming and also the Central Appalachian Basin in Western Virginia have all come on screen after the tax credit. And some of these look to be very, very attractive plays, particularly the Uinta Basin and Powder River Basin.

But still most of the production comes from the San Juan Basin, over 900 Bcf in '97 with about eight Tcf remaining. The other basins are quite small. But we do think the Uinta Basin, the Raton and Powder River are going to grow

to be much larger production areas in the future based on the economics of production.

Finally gas shale is by far the smallest but still significant. Gas shales tend to be very thick, low gas content, low productivity. But smaller independent operators, not the major production companies, but some of the smaller ones can find it to be a very attractive play.

Most of the production comes from the Michigan Basin here just in the northern part of the state, the Appalachian Basin comprising many states in the Appalachian area like Ohio, New York, West Virginia. And then the Fort Worth Basin down in Northern Texas.

There are other basins and particularly in California I might point out in Monterey, shale and stratigraphic equivalence are now just recently thought to have gas shale potential. There are wells that have produced more gas for a longer period of time than can be reasonably explained from the conventional reservoirs. And it's just starting to be an R&D area for some companies.

And here's how the gas shale basins stand. Fairly small, 200 Bcf; red for the Michigan basin a hundred Bcf; production for the Appalachian Basin. Both of these have about 1.8 Tcf of reserves remaining.

So that's kind of an update on the current status of the industry.

Next I would like to talk about a model we have developed, my company has developed, to try to capture the economics of this entire new class of resource. And the particular model I will talk about is one we developed for the Department of Energy, the U.S. Department of Energy. We call it the "Model for Unconventional Gas Supply," for want of a better term, MUGS.

And this model really just deals with the resource economics. It doesn't get into the demand side at all. This is just gas that goes into a pipeline. And from there it moves to users.

But we have quite a lot of detail on the resource side. And just some of the modules that comprises this model I will talk about is a resource base and productivity. There is a technology impacts and timing model. As you might know, technology is very important for bringing on these new resources. Twenty years ago they were much less important, almost nonexistent for coalbed methane gas and many of the gas shale plays. And it's really been new production and completion and stimulation that has brought these resources on.

By the way, DOE uses this now in their large oil and gas supply model which feeds into something called NEMS, which is the National Energy Model. And they publish the results of this in an Annual Energy Outlook. Basically the federal

government's forecast into the next 20, 25 years of energy supplies in the United States. This is just one small piece of their natural gas supply.

Now our model can take a variety of price tracks. And, in fact, we used it to run a California Energy Commission case where we plugged in the average wellhead gas forecast as supplied by the Energy Commission. That's the line shown in blue. It drops down in '99 to about a buck sixty per Mcf. And then it climbs very slowly up to about a dollar ninety-five for Mcf in year 2020.

I am also going to show another sensitivity case, and that is EIA's recent gas price forecast which is somewhat higher. It doesn't drop below 210, and it climbs to about 250. And this will, as you will see, will have a very powerful impact on the natural gas decline.

This is the result of our forecast. You can see history to the left of 1997 with a very strong ramping-up of tight gas in red, gas shale in blue. And coalbed methane really coming out of nowhere in the late '80s is now about over a Tcf of production. That's five percent of natural gas production in United States comes from something that no one even knew about twenty years ago.

And to the right of '97 is our projected forecast. We have a peak coming in very early in '99. And then as the gas price is forecast to fall, correspondingly, we have a very

steep dropoff in our predicted production of natural gas from unconventional resources particularly in the tight gas area.

So these resources are very sensitive to price. On the average, they are not extremely high margin, although some of the plays can be very profitable, indeed. But still they are quite sensitive to price. And given this price track production really linked to drilling, drilling will fall off, recompletions will fall off and production will also drop. And then only recovering later in 2015 to 2020 as the gas price finally gets high enough and technology improves over time to warrant significantly further development.

This is another forecast using the DOE-EIA price track which is more optimistic. And I am not qualified to comment on the price forecast because that's really not my particular area. But it does have a much less of a negative impact on unconventional gas production. We do see somewhat of a decline, but not nearly as steep as the Energy Commission's price track, and then a very strong increase after 2010 as the higher prices in the better end of the forecast as advanced technology kicks in. And again it is particularly sensitive to the tight gas resources.

Both of those graphs I just showed you were using what we might call "reference technology assumptions." And that means we are projecting the previous pace of technological improvement we have seen in the last ten years

or so into the future. Now this may not happen.

For example, there's been a lot of cutbacks at the major oil companies in R&D. Many of the R&D centers from companies such as Exxon, Mobil, Shell, et cetera, have really -- a lot of the staff have switched over into more of a service company mode where they are actually not thinking of completely new technologies. They are kind of applying existing technologies that are in the pipeline.

And also a lot of the research institutes, like the Gas Research Institute, their budgets are being cutback quite a bit. And we don't see, perhaps, in the near future the same level of R&D spending.

So it is useful to have sensitivities to technology. And the blue line in the middle here is what I just mentioned is referenced technology which is extending the mirrored history out into the future. And that's the case I showed on the previous graph. This is for all three resources combined.

The green line shows a less optimistic view for technological improvement. This might be related to a low oil price environment where you have much less R&D spending in the industry. Maybe GRI, the Gas Research Institute, as is planned, disappearing as we know it. Their budget going from $200 million a year a couple years ago to essentially zero within five years. And this alone has about a two Tcf impact. That's a four Tcf production per year in the year 2020 under

reference price. That's only two Tcf of production under the low technology. So it is very sensitive.

In addition, there is a high technology case where we have a much stronger R&D program within the private sector, more spending from DOE, from the Gas Research institute, et cetera. And this has a very strong impact, particularly in later years. And we can actually envision up to nine Tcf of production from unconventional gas in the year 2020, which is about double the current rates.

Now I have talked a little bit in general terms about what is, you know, technology. But here I would like to go through some of the particular technologies that are very important. There are 10 of them, and I will just cover them very quickly. But each of one of these is modeled within our unconventional gas model in a particular way so that it is linked to the correct resource which the model should impact. It is not just extending an econometric line by two percent a year into the future. It is actually linked to the production of each individual play.

And one of the most important is in the area of basin assessments. And you might mention coalbed methane. Until the 1980s when the DOE and the Gas Research Institute funded some of these really geologic and engineering studies of what is in the ground, what kind of resource is out there, that's really what started the coalbed methane production area which

today is five percent of our gas supply in America. And this has specific impacts within our model, but I won't go into that right now.

Two, another area is extending resource characterization which increases the pace of new development.

Three, is probably more easy to picture. This is diagnostics and remediation for development performance. A lot of these wells initially don't produce very well because the stimulation, the completion, the way the well was actually completed to link with the reservoir was not the best practices. And there are thousands of these wells over time. Operators learn in a specific area how best to hydraulically stimulate or link the well.

Four, is very important for unconventional because this is helping to find the naturally fractured areas, areas which have naturally high permeability. There is exploration of natural fracture detection using seismic methods, using remote sensing, using structural and stress modeling. This is probably the single most powerful impact on well productivity.

Number five, matching and modeling the correct geology and technology to the resource is very important.

Six, improve drilling and completion technologies. These are technologies that can also help other just conventional gas resources as well.

Seven, lower cost drilling and stimulation obviously

has a very big impact.

Eight, lowered cost water and gas treating. These are really more environmental technologies. A lot of these wells produce large amounts of water in addition to gas. And the water has to be safely handled, processed and then disposed of.

Gas processing is less important because this tends to be a low-capacity production.

Advanced well completion, number nine, and then environmental mitigation, number 11. These are also important, because some of these basins, like the Green River Basin in Wyoming, are actually under constraint. The operators are not allowed to drill as many wells as they would like to because there is concern about air pollution with the gas compression systems.

So new technologies that would mitigate the emissions problems they are having out there would be a very important driver to increasing supplies.

Let me just finish the technology section with one I am particularly interested in. And perhaps you are familiar in California in the heavy oil fields in Kern County. They are injecting steam to enhance the recovery of oil.

Well, there's a very similar, crudely speaking, there's a very analogous technology for coalbed methane, and that involves injecting CO2, carbon dioxide, into an injector

well. This well does nothing but inject CO2 into the reservoir which, in this case, is that gray-colored coal seam here.

And then the CO2 flows into the reservoir. The coal seam prefers to absorb the CO2, and it lets go of the methane. And it's basically a hundred-percent exchange within the reservoir.

Now the methane is free to flow to the production well. And theoretically, using this CO2 injection, CO2 flooding technology, you can recover about a hundred percent of what is in the reservoir as opposed to maybe 30 percent under conventional technologies.

MS. SHAPIRO: Steve, can I interrupt you? What happens to the CO2 when it comes out? Then you have to separate it and inject it again?

MR. STEVENS: Well, this is a very new technology. This is only being applied in the San Juan Basin in one small pilot. We do hope it will spread to large-scale production. And in two years they still have not had any breakthrough of CO2 to these production wells.

But they do expect it eventually. And they are fully prepared to recycle the CO2 because it's very expensive. That is their biggest operating cost. They buy the CO2 from Shell Production Company, Shell CO2 Company.

But you're right. Eventually this well will have to

be equipped with some separation and recycling facilities. And then the CO2 would go back to the injectors.

The other very interesting twist is this is perhaps the only way to make money sequestering CO2. And you know with concerns about global warming, people are looking at ways to dispose of CO2: Pump it into the deep ocean, turn it into chemicals, all kinds of things. None of them make money. They are all strictly a cost and a very heavy cost at that. And this is important for large producers of CO2 like powerplants and the utility industry, large commercial users.

This is one method where you can sell the CO2 instead of paying somebody to take it away. You can actually make money as an operator taking someone's CO2 and using it in your system.

So we are really keeping an eye on this technology. And there is a lot of international interest. This operator gets people every three days coming from Holland, Japan, all over the world, because it's such an incredibly seemingly, you know, perfect technology for sequestering CO2, disposing of CO2 and also making lots of money.

So, in conclusion, we see under the California Energy Commission's price track, we see unconventional gas supplies declining into the future, but recovering slowly after 2010.

We are really going to need higher wellhead gas prices over $2. And then you will really be needed to

stimulate another two Tcf per year of unconventional gas supply by 2020.

From California's perspective, the new frontier of unconventional gas basins are going to be in the Rockies for the most part. The Green River is a very, very large resource, but a very difficult to develop resource. The Green River and many of the other Rocky Mountain Basins, including some of the what are thought of as mature, like the San Juan or Piceance Basin and many other areas we do see and still see room for a lots of supply in those basins.

And the technologies that are going to be particularly important are those that help us find the sweet spots, the high permeability fairways and other buzz words, improved technology, particularly in the areas of drilling completion and stimulation to reduce the final costs and increase supply.

And I'd be happy to take questions. I also want to mention I'll be here after lunch if anyone would like to discuss this in more detail.

PRESIDING COMMISSIONER SHARPLESS: Thank you very much, Mr. Stevens.

Are there any questions?

Yes, Bill.

MR. WOOD: Scott, going back to the San Juan Basin and the coalbed methane that you were discussing there, just

to throw out this idea. We've been using in our analysis for coalbed methane an ultimate recovery of about 27 Tcf of coalbed that would include production as well as presently proven reserves that are there.

And that's principally why our analysis has been associated with the fruitland. But I notice that you indicated the Menefee in there also, which we have haven't included in any of our analysis.

How does this 27 Tcf, in your mind and with the level of work that you've been doing in that area, does that seem reasonable or are we a little on the high side?

MR. STEVENS: Well, let's just build it up. There is currently -- they produce a total of about five and a half Tcf. There's another 9 Tcf remaining. That's about 15 Tcf that's already been booked, if you will, to date.

MR. WOOD: Yes.

MR. STEVENS: In addition with in-fill drilling, with recompletions, with new areas coming on, just from the fruitland, we think it's very reasonable to have 20 Tcf.

With advanced technologies like this CO2 injection, you could actually increase that by 50 percent very easily, to 30 Tcf.

MR. WOOD: Okay.

MR. STEVENS: And as far as new formation such as the Menefee, we do include the Menefee in our model, but we

don't have a very high opinion of it. It's really in what we call the "hypothetical play." It's the least, the most possibly and the least reliable. I don't know. I could check the numbers, but I think they're well over $5 an MCF on which to recover gas from the Menefee. But it's still not very well constrained. So I think those numbers sound are very reasonable.

MR. WOOD: Okay. Thank you.

PRESIDING COMMISSIONER SHARPLESS: Scott, did you have a question?

MR. TOMASHEFSKY: Yes, just following up on Bill's question.

Would you expect to see some ramping-up of San Juan Basin production? Because things are going up steadily, although some of the testimony we've had in the past has suggested that San Juan production would just basically go through the roof. And we're not seeing that through some of the historical numbers you have.

And given this CO2 technology, would you expect, say three or four years down the road if it does take, would you find another ramp-up of coalbed methane production in San Juan?

MR. STEVENS: I doubt it. I think the CO2 flooding would really be more to maintain the current level rather than ramping up to a new plateau.

We do see continued increase. It's now 918 Bcf from 1997. It's still growing at perhaps four to five percent a year. But we don't see any big breakthroughs coming. But, of course, there are other resources in the San Juan Basin, other formations which, like the Louis Shale, which do have a lot of potential.

But your question was specifically the coal scene.

MR. TOMASHEFSKY: Right.

MR. STEVENS: Yes.

MR. TOMASHEFSKY: And one other question, actually.

In our last forecasting work, we had tight gas production in the Green River Basin also shooting out through the roof toward the end of the 20-year forecast period. And that was based on some of the USGS work that was done. And we had several people come and testify to whether that estimate was too high, which we came to the conclusion it was.

We were getting, I think, estimates near one Tcf in that region of wellhead and tight gas. And I was hoping you might be able to comment on what you consider to be growth in that area as opposed to what we've actually thrown around in some of our model resource.

MR. STEVENS: We are actually very optimistic about the Green River Basin and about the technologies that are going to be needed to produce the gas that's in the ground. Of course, there's hundreds of Tcf resource theoretically

recoverable.

And I would have to check our exact numbers, but I think that sounds very reasonable actually. We're actually looking on the more optimistic side for the Green River Basin based on our experience.

MR. TOMASHEFSKY: Can I go for three?

PRESIDING COMMISSIONER SHARPLESS: Sure. Go ahead.

MR. TOMASHEFSKY: The other one also relates to some of the areas in the Northern Great Plains, which from estimates seem to have a lot of gas in the ground, but nobody seems to be projecting there would be a lot of production from those areas. And you've got pipes all around the area that are taking gas from Canada through to the Midwest, but nothing really taking it from the Northern Great Plains. Is that an area that potentially could grow?

MR. STEVENS: It's not one we put a lot of merit on. Again, it's a very high cost area, based on our understanding. But you're right, there's not a lot of drilling experience; and maybe with the pipelines nearby that will increase understanding. But currently as modeled, we don't have that as a really big coming-on in the next 25 years.

PRESIDING COMMISSIONER SHARPLESS: Jairam.

MR. GOPAL: Regarding the projections that are too high based on the MUGS analysis, you have a depth which is followed by a slight increase when you consider the CEC price

for a significant increase, when you consider the ERA price. Is that going to offset conventional production or is that not a parameter considered in that analysis?

MR. STEVENS: Well, our model doesn't cover conventional, so we can't -- and we haven't done any feedbacks with DOE to see if our extra supply is going to hurt somebody else's conventional gas.

I guess I wouldn't expect it to be impacting conventional pretty much. So I guess not.

PRESIDING COMMISSIONER SHARPLESS: Any other questions?

Then thank you, Mr. Stevens.

MR. STEVENS: Thank you.

PRESIDING COMMISSIONER SHARPLESS: Perhaps we'll call up Mr. Greenwood, and that will give you plenty of time.

MR. GREENWOOD: Good morning. I appreciate the opportunity to visit with you for a few minutes.

Bill gave me a call last week and asked if I could make a very short presentation on Questar and our resent acquisition of the ARCO Four Corners Oil Pipeline.

PRESIDING COMMISSIONER SHARPLESS: If you could give, for the record, Mr. Greenwood, your affiliation?

MR. GREENWOOD: Sure. My name is Ned Greenwood. I'm with Questar Corporation in Salt Lake City, Utah. I'm a director of the Southern Bell Pipeline Company.

I thought before I would get into the description of the pipeline, maybe I would just mention briefly, Questar Corporation is a $2 billion corporation. We're headquartered in Salt Lake City, Utah.

Through our various subsidiary companies, we have operations and exploration in: Development, gathering and processing, energy trading, natural gas transmission and storage, natural gas distribution, and telecommunications.

What I'll do is just give you a little bit of history first. And the pipeline, the ARCO Pipeline was built in 1957 by a group of oil companies. And the purpose was to transport oil basically from the Four Corners area to Long Beach, California, and the refineries.

In 1977, ARCO purchased the pipeline from the other partners of the consortium. And they then reversed the flow of the pipeline to go now from the Long Beach area up to the Four Corners area and tied into another pipeline called the Texas-New Mexico pipeline that actually took the crude down into the Houston area.

In 1998, ARCO purged the oil pipeline of all the oil. And then in November of this year, we acquired the pipeline from ARCO. Currently the pipeline sits in a nitrogen state. The oil has been removed, and it will remain in that state until such time as it can be converted to gas service.

Just a quick description. There's actually three

segments. This longer piece right here is called Line 90. And it's about 600 miles of 16-inch pipeline. It has another piece of about 18 miles. It's also 16-inch. It goes up into the Uinta area, the Red Mesa area. And then you have 12-inch and a small portion of 22-inch that extends into New Mexico.

In addition to the pipeline, we acquired 12 pump stations and a microwave and radio system. The purchase price was about $38 million.

Our plan is to convert the entire line to gas service for delivery and to the Long Beach area. We will have about 18 miles of pipeline replacement, some 54 miles of extensions, seven compressor sites. And I would add six of those are at existing pump sites. One will be new. We will have one potential gas plant receipt point, -- and I can go back through these in a moment -- but that will be here in the Lobo area with El Paso. Six potential interstate pipeline connections. You will have three in this area, one with El Paso, one with Transwestern and another one with TransColorado. And I should say that we're also a 50-percent partner in the TransColorado partnership as well.

Let me give you the other three. There will also be three other interstate pipeline connections: One here at Topak with El Paso and Mojave, and another one in the Needles area with Transwestern.

We will have three potential distribution company

interconnects; Here again in the Topak area with Socal Gas and with PG&E and then up here near the Mojave compressor site, another potential with Southwest Gas.

And then finally we will have a minimum of five potential end-use delivery points, four of them will be along the pipeline here through the Navajo and Hoppe Reservations where we will be making gas available to those communities. And another delivery point here in the Long Beach area to some of the refineries in the Long Beach area.

The total price of the conversion will be approximately $156 million. And what we have is really a pipeline that we can segregate into two components. We're calling this segment here the Eastern segment. And it can deliver upwards of 87,000 decatherms a day. And then we have the Western segment which can deliver approximately 120,000 decatherms a day.

So it's possible to actually deliver gas into this area and take additional gas from our interconnects and transport that gas to the Long Beach area.

The transportation rate will be approximately 35 cents a decatherm. And our in-service date is June 1 of the year 2000.

We are in the process of getting ready to file our third application. We hope to have that filed this week. That application will also be in conjunction with our EIS-EIR

environmental reports. We had hoped when we purchased this pipeline that we would not be required to follow the expanded EIS-EIR environmental reports because we feel like our impact is minimal with respect to this pipeline as far as impacting the environment, but we were strongly encouraged to do otherwise. And so that's what we have doing.

I would say that of the some 18 miles of pipeline replacement and reroutes, only about four miles of it is in California and it's here in the Needles area.

We also have some additional pipeline extension, some 54 miles. But, again, the majority of this is in this area here where we're actually tying into the pipeline here, down to Topak. We're also building an interconnect between our TransColorado pipeline, a 20-inch line that will go across here and connect in with the 12-inch pipeline.

Are there any questions?

PRESIDING COMMISSIONER SHARPLESS: Excuse me. You probably did say this. But what did you say the capacity of the pipeline was?

MR. GREENWOOD: The capacity of the Eastern segment here is 87,000 decatherms a day. And then for what we are calling our Western segment, it can be upwards of a 120,000 decatherms a day. In this area --

PRESIDING COMMISSIONER SHARPLESS: And that's dependent on what, it can be, you said?

MR. GREENWOOD: Well, the limitation in this area is because of the 12-inch pipeline that we have here. We do not deliver as much gas, and we don't have as much compression on this side of the pipe as we do down here.

In this area will be running the pipe at about 1050 pounds per square inch. As we move into this area, it will be closer to 975. As we move into the residential areas in California, it will be reduced down to about 800 pounds per square inch.

PRESIDING COMMISSIONER SHARPLESS: And so this capacity includes all of the expansions that you spoke of?

MR. GREENWOOD: Yes, ma'am.

We had an open season in October of last year. We had some 22 bids from 15 different companies that were submitted. We are now finalizing our negotiations with several companies who will be then taking capacity on this pipeline.

It will be a FERC jurisdictional pipeline. FERC will be the lead agency with respect to the EIR-EIS. But we're also working with the California Land Commission department as well on our environmental report.

PRESIDING COMMISSIONER SHARPLESS: You're talking about the California State Lands Commission?

MR. GREENWOOD: Yes, ma'am.

MR. WOOD: Will this be a Section 7 or an OES or

they call it the other operation; Section 7 of FERC, right?

MR. GREENWOOD: It's open access.

MR. TOMASHEFSKY: It's open access.

MR. WOOD: It's open access?

MR. GREENWOOD: Yes.

MR. WOOD: What's the principal area of supply you're expecting? You're coming out of the San Juan, but are you going to be taking --

MR. GREENWOOD: We can take here from the Piceance to the TransColorado. You have the San Juan, you have Permian gas that will be coming up. It will also be having connections down here with El Paso and Transwestern. So there's several different supply sources that we can access.

MR. TOMASHEFSKY: And what are the general terms of the length of these agreements that you're looking at? Is it 20-, 25-year arrangements that parties are signing up for or is there --

MR. GREENWOOD: We'd love to have those. If you know of anybody that would do that, I'll give you my card.

(Laughter.)

MR. TOMASHEFSKY: That's 25.

MR. GREENWOOD: Varying terms. The majority of them are over five years.

MS. BAKKER: As in longer than five years or covering?

MR. GREENWOOD: Yes, ma'am.

MS. BAKKER: Okay.

PRESIDING COMMISSIONER SHARPLESS: Are there any other questions of Mr. Greenwood?

Jairam, did you...

Oh, yes, would you like to identify yourself for the record, come up to the microphone?

MR. BILLINGS: Yes. I'm Kevin Billings. I'm with Kern River Gas Transmission out of Salt Lake City also.

You said 35 cents; is that on the Western section? Would that be for the Cal border into Long Beach or is that from the Four Corners Region all the way into Long Beach?

MR. GREENWOOD: We can actually segment it where you will have a 35-cent rate approximately on the Eastern segment and the 35-cent on the Western segment. So you can segment it.

MR. BILLINGS: So if you were to go from your TransColorado it would be approximately 70 cents, then? If you were take your Eastern and your Western segment?

MR. GREENWOOD: Well, if we were to take the gas from this area down in here, then it will be the 35-cents.

MR. BILLINGS: It will be 35 cents.

MR. GREENWOOD: Most of the shippers that we are talking to that are putting gas in at this point are only taking it to this point here. So we really don't have any

shippers right now that are willing to take it to the full length of the pipeline.

MR. BILLINGS: Okay. I understand. Thanks.

PRESIDING COMMISSIONER SHARPLESS: Any other questions of Mr. Greenwood?

Mr. Greenwood, I'm going to thank you for coming and giving us this presentation.

MR. GREENWOOD: My pleasure.

PRESIDING COMMISSIONER SHARPLESS: You have been very helpful in trying to build our base case assumptions.

Yes. Scott.

MR. GOPAL: We will next have Scott Tomashefsky who will take the information that was presented by Scott Stevens, combine it with the resource estimates that were used in our assumptions of the previous forecast and briefly describe how we will go about for this cycle.

MR. TOMASHEFSKY: Thank you, Jairam.

Good morning, everyone. Thanks for coming.

Here it provides Staff testimony on our latest update to the resource cost curve, so actually our work is in process. We haven't done it all yet. We're just in the beginning phases.

What I will try to do in the next few minutes or so is provide a very general overview of what our resource cost curves look like in the North American regional gas model. A

lot of you have heard this portion of the presentation over again time and time. So I will keep that brief.

We will look at some of the modifications that we are looking at right now in our cost curves. And I will give you a example of how some of the reserve data is taken from EIA information and some of the data that Scott Stevens has provided to put into our models. And then I will take any questions and answers.

The cost curve itself in the NARG model consists of five major components. We have curve reserves. We have potential resources. We also have the capital and operating costs and also the production profile which allows the models to determine how the gas will be produced from particular areas throughout the NARG network that Jairam had described earlier.

You can see in this example. This is just the Federal Offshore Gulf Coast. We had 26 Tcf approved reserves and about another 95 of potential resources. And that does not include reserve growth over time, which we spent a lot of time in the last forecast developing putting into the model for the first time. And we're not going to address that in this discussion.

In terms of the enhancements to the cost curves, last time we did this we had the benefit of USGS performing their 1995 national assessment, which took them several years to do,

a very comprehensive piece of work. We worked fairly closely with some of their staff to come up with a lot of the estimates.

They are in the process of doing another update. It's not defined how extensive that update will be. But we don't have the luxury of those estimates for this case. So what we are assuming is we are going to leave the capital operating costs unchanged in real terms.

What we have changed and what we change each time we update the forecasts are the crude reserves and RP ratios to preserve the production ratios that are published by EIA in their National Gas Annual Report. And then we take the data that Scott provides to take the unconventional resources, apply it to our cost curves in the model and then back into the conventional resources that are remaining so that the sum will equal the EIA data where we have some of the unconventional detail in the model.

PRESIDING COMMISSIONER SHARPLESS: So, Scott, the capital costs that we used in the last ER that were based on 1993 figures are --

MR. TOMASHEFSKY: Based on 1993 figures.

PRESIDING COMMISSIONER SHARPLESS: -- are going to be carried forward in this analysis?

MR. TOMASHEFSKY: That's right.

PRESIDING COMMISSIONER SHARPLESS: Because that's

the best we can do?

MR. TOMASHEFSKY: That's the best we can do. That's a simplifying assumption. And a general rule of thumb, just looking at the operating costs, the added inflation costs would be offset by some of the technology enhancements over time. So there's not really much we can do about that at this point.

The California data comes out of our own Department of Conservation, Division of Oil and Gas. They put out an annual report and a very extensive publication on the gas production of California. So we use that to get a little bit more focused on our own state interest.

PRESIDING COMMISSIONER SHARPLESS: Is there information, Scott, one that's put out by our own State and Gas Division based on the most current 1997 data, or is it even more current than that?

MR. TOMASHEFSKY: It's based on 1997 data. It's an annual publication that has preliminary numbers that come out usually in the summer of the following year, and the final report is published towards the end of the year. Just an example of the 1997 report. It has data by field, by district on oil and gas and geothermal resources.

This provides a hopefully not convoluted explanation of how we derive reserve and production estimates. And essentially what we do is we take a look at what we define

would be as a region. And what we've taken for the Rocky Mountain supply region, is we include all of Utah and a portion of Colorado and Wyoming.

These percentages are based on data that was provided by Dwight's through EIA that allowed us to try and identify particular areas throughout that state that would be representative of particular basins, so that we have about 87 percent of Wyoming production included in the Rockies. The other portion is in the Northern Great Plains. The Colorado, we have that split up between San Juan and the Rockies.

So those numbers are based on some historical information. And what we do is we come up with a total, a total number where we have 1229 Bcfs, a 1.2 Tcf production in 1997 based on 16.2 Tcf of year-end reserves.

Then what we do is we take Scott Stevens' work and we try to identify which unconventional resources are built into those particular areas. And we apply that to those cost curves in the model and then the difference becomes a conventional resource estimate.

So that is kind of how we do it. And we could not do it unless we have the unconventional data. Because EIA provides some of the information related to coalbed methane production, but they don't get into some of the detail that USGS was able to provided us when we did our work for the last forecasts. So that's essentially how that works out.

In terms of our resource base, the description of what is in our resource base is in our 1998 Natural Gas Market Outlook, which is available on our web site and also through publications.

Just to touch on it very quickly, we have about 90 cost curves in the model with the Rockies providing the most detail. We have more than a dozen curves in the Rockies.

The resource base itself, if you will look at the potential on the reserve growth estimates that we have listed up here, they are identical to what they were in the previous case. And this is again a working product, so we need to see what type of resource estimates we can get that are more updated on the potential side.

The proved reserves have been updated, and I think they are about six Tcf higher than they were in our last case.

As you can see also, the Gulf and the Rockies account for about half of the total resource base in the U.S. So we spend a lot of time trying to figure out what is going on in the Rocky Mountains.

And you can also see the reserve growth is very important. That comprises about 20 percent of the total. That's why we spent so much on it last time. And, all in all, California reserve estimates are fairly small relative to most regions.

Finally, our next steps look simple, although there

is a lot of work associated with that. We still need to go and look at our Canadian cost curves and update those prove reserves and RP ratios and also see what we have or what we can obtain from both the National Energy Board and Energy Research Institutes. And since they use the same model for their analysis, so we have a very nice partnering arrangement where we do share a lot of information. And they take a lot of the data that we use in their models and vice versa.

We'll probably look at reserve appreciation and see how we can improve that process. And we're not really sure at this point what we're going to do with that. But we have had a lot of discussion on it in the past. We will certainly need to see how that responds to modeling in the future.

But also we have got to look at the real rate of return for owners and producers. And Leon is going to touch on that shortly.

This particular feature of the model has a powerful impact on price trends and escalation rates over time. And given low inflation over the last two years, we are trying to answer the question of whether there has been an underlying shift in how rates of return over time should be handled.

So that is generally an update on what we are doing, and I will take any questions if there are any.

PRESIDING COMMISSIONER SHARPLESS: On the reserve appreciation which was an issue last round, and I assume will

still be an issue, we plan to deal with the problem of using historical data versus time varying based how, Scott?

MR. TOMASHEFSKY: We had talked about having additional model work being done to become more time dependent. Since that discussion has gone on, the model developers are working on a Windows' based model that we have not incorporated that. And we are in the testing phase to make sure it does what it does before we actually start using it again.

And so in terms of what we have in our current model structure, we probably will not be able to make it time dependent. And we'll need to take that into consideration as we work through this next forecast, but I would expect --

PRESIDING COMMISSIONER SHARPLESS: So we will use the same type of methodology we used in the last run with sensitivity --

MR. TOMASHEFSKY: That would be the approach.

PRESIDING COMMISSIONER SHARPLESS: -- scenarios of sorts?

MR. TOMASHEFSKY: Yes. Yes.

PRESIDING COMMISSIONER SHARPLESS: I believe the other problem we had on the last run also was our estimates on production from the Rocky Mountain region were high.

MR. TOMASHEFSKY: That's right.

PRESIDING COMMISSIONER SHARPLESS: How are we

dealing with that this year?

MR. TOMASHEFSKY: Two ways, actually. The other producer work has an impact on what happens there, which is one way. We have also looked at looking at Scott's work. I think that will help us at least focus on our past lab test approach.

The other thing we need to do is we will be in touch with the U.S. Geological Survey because they have indicated they were going to do some additional work in the Rockies. And at a minimum we will at least check to see if the capital operating and production profiles we have associated with those cost curves are still consistent with their thoughts on what is available from those regions.

So I think those three in combination should at least allow us to address the problem a little bit.

PRESIDING COMMISSIONER SHARPLESS: Are there any other questions by individuals?

One? Yes, sir. Please come forward and give your name and your affiliation.

MR. FUNKE: My name is Carl Funke, F-u-n-k-e, from San Diego Gas and Electric.

In that the unconventional appears to be based on the forecast of the prices, would you explain the iteration process in your modeling to then use that to come back with another forecast?

MR. TOMASHEFSKY: Sure. The price information that Scott provided actually we don't use. What we are interested for our purposes are the actual production and reserve estimates from historical standpoints.

So the key numbers for us are 1997 production, 1996 year-end reserves. The other data that shows up from 1991 to 1998 at least is a way for us to look at trends and to see as we take those estimated numbers and then compare to our projected numbers whether we are in the ballpark of where we should be or where we are comfortable with.

So the price projections are good to provide us information as to how other parties see our prices.

PRESIDING COMMISSIONER SHARPLESS: To see how close or how far off we might be from other models?

MR. TOMASHEFSKY: That's right.

PRESIDING COMMISSIONER SHARPLESS: Okay. Thank you.

Any other questions?

(No response.)

PRESIDING COMMISSIONER SHARPLESS: All right. Thank you, Scott.

MR. GOPAL: The responses are made by Scott was to look at oil and producer discount rates. And that directly leads us to the next item on the agenda today. Leon Brathwaite will address the issue of how we need to deal with the discount rates in the model.

Leon.

MR. BRATHWAITE: Thank you, Jairam.

Good morning, Commissioner, Advisors.

PRESIDING COMMISSIONER SHARPLESS: Good morning.

MR. BRATHWAITE: Thank you for giving me the opportunity to present this issue to you.

We raise this issue of discount rates in the nine model because the rates significantly affect the shape and level of the eventual forecast we will come up with. A little bit of background.

On the supply side of the model, two economic agents exist: Their owners, these are the property holders; and the producers, these are the crude oil and natural gas operators.

Previous presentations to this Committee have suggested owners and producers face different risk profiles. As a result, their discount rates should vary accordingly.

The last forecast completed by Staff used producer and owner discount rates of 10 percent and four percent respectively. Staff, however, has reconsidered this issue.

So the question we are left with is what is the appropriate rate of return that should be used to discount future cashflows. And this is a long-term model that goes out 20 years. We need some mechanism by which we can discount any cashflows that occur in the future.

Dr. Solow, a prominent finance professor, argued in

1963 that the discount rate within an economy is a function of the real growth rate of the economy. This argument suggests discount rates should approximate the annual rate at which the economy increases the production of consumption goods.

Solow's assertion does not directly address the issue of differences in risk profiles between economic agents.

I'm going back to our original question: Does the risk profile of owners differ from that of producers? Both producers and owners must bear an opportunity cost of capital in order that supplies come to the market. The returns of both the owners and the producers arise from the production on the property. As a result, both owners and producers face the same level of uncertainty from any particular investment.

There's a principle here we must consider. At market equilibrium, all equivalent investments or saving opportunities must offer the same returns. And that's an important idea which we will use later on in this presentation.

Let's talk about how the model views some of this stuff.

The model examines the economic behavior of the natural gas industry as a whole, not the economic decision-making of individual investors. Also the model does not account for differences in risk aversion between economic agents. And remember the two economic agents we are talking

about here are the owners and the producers.

The model uses perfect foresight, which means it sees all transactions into the future. This situation can be properly characterized as a certainty equivalent of potential risky investments.

Now what do I mean by "certainty equivalent"? Let's use an example. An investor has a forecasted cashflow of, say, $2,000 a year from now. But there's only a 50-percent chance of actually receiving that cashflow. He may ask himself, he or she I should say, may ask himself -- pardon me, Commissioner -- he or she may ask himself: Is there a lower but a short cashflow that I will take instead of the risky $2,000? So it might be $1500. We don't know.

The certainty equivalent can be used in a model because the model uses this perfect foresight. It sees everything. Given that, is there any reason then to expect the rates between owners and producers should be different? Given the way the model views the world, is there a difference in the risk profile of those two economic agents? These arguments suggest not.

Let's talk a little bit about market behavior. If the marketplace violates the equal-rate-of-return principle, which I spoke about a little while ago, then arbitrage opportunities exist. Investors will quickly push rates of return back into equilibrium.

In our particular case, owners can become producers through equity investments on capital markets. Also producers can become owners by actively seeking to purchase potentially productive properties. This again leads us to the conclusion that if expected rates of return vary, arbitrage opportunities exist and market participants will quickly eliminate the differences.

As a result, is there a discount rate or rate of return that produces this certainty equivalent? And remember I just spoke about the certainty equivalent.

Historical observations can give us a close approximation. If we recall Solow's assertion, the discount rate must be a function of the real economic growth, that is a production of consumption goods. The production of consumption goods can be approximated by a representative basket of common stocks.

Over the last 50 years, common stocks have yielded nominal rates of 10 to 12 percent and real rates of six to eight percent.

So where does all this lead us? Investors usually measure market performance by looking at a rate of change of the Standard and Poor 500. The Standard and Poor 500 is a basket of common stock usually considered representative of the market as a whole. The returns from the Standard and Poor 500 or an equivalent basket of common stock represent: The

total outcome of all investors; the supply and the consumer; the less risk averse and the more risk averse; the speculator and the arbitrage.

In other words, average returns from the Standard and Poor 500 gives us a close approximation of the certainty equivalent. Real rates of return from the Standard and Poor 500 averaged about 78 percent over the last 50 years.

Now why the Standard and Poor 500? Fifty years ago an investor who bought shares in a market port folio represented by the Standard and Poor 500 was almost assured of a seven- to eight-percent real return. Again, we are talking about the certainty equivalent.

And, of course, I must mention, we are looking back with 20-20 hindsight. And we are assuming those assumptions, those things that came from the past will also keep us going in the future.

If you remember the equal-rate-of-return principle also indicates a discount rate for producers and owners should not differ because they are equivalent investments.

As a result, I am recommending we use a real return, a real discount-rate return for both owners and producers of five and a half percent.

PRESIDING COMMISSIONER SHARPLESS: Seven point five.

MS. SHAPIRO: Seven and a half.

MR. BRATHWAITE: Sorry. Seven and a half percent.

That's right here. Sorry.

PRESIDING COMMISSIONER SHARPLESS: You were on a roll there.

MR. BRATHWAITE: I was on a roll there, Commissioner.

And thank you for allowing me to make this presentation.

PRESIDING COMMISSIONER SHARPLESS: Right. This seven and a half percent came from looking at the real returns from the Standard and Poor's 500 averaged between seven and eight, and you just cut the baby?

MR. BRATHWAITE: Yes, Commissioner.

PRESIDING COMMISSIONER SHARPLESS: Seven point five?

MR. BRATHWAITE: Yes. That's right there.

MS. SHAPIRO: Leon, you're in big trouble because I understood it.

MR. BRATHWAITE: Oh, you understood it. Oh, my God.

MS. SHAPIRO: Yes. And I remember sitting through the discussions before when we said the producers were more willing to take risks and the owners were not. And I struggled very hard to understand it, and I finally understood it and I bought it.

Now here we are and you're going back on it. You are reversing where we are.

MR. BRATHWAITE: Yes.

MS. SHAPIRO: But I don't want you to explain that. What I would like you to explain is: So what? How does this affect our cost curve. How does this affect our forecast?

MR. BRATHWAITE: Well, just to put in -- as compared to --

MS. SHAPIRO: How does it affect that we have made it the same when before we argued they were very different?

MR. BRATHWAITE: Different. Okay.

MS. SHAPIRO: So how does making it be the same change things?

MR. BRATHWAITE: Both discount rates affect the level of the price track we have eventually come up with.

A higher discount rate for producers raises the level of the price track. And a lower --

MS. SHAPIRO: Right. If they have a lower rate of return then the whole price track is lower?

MR. BRATHWAITE: Yes. But the owner's discount rate does present a slightly different problem in the sense that if you have a higher discount rate, it lowers the -- there is a general lowering and also a general flattening of the price track. So it makes a significantly difference in the numbers we choose to put into the model.

Now if I could -- I am sorry I did not bring a slide on this. But can you see this from there?

MS. SHAPIRO: Yes.

MR. BRATHWAITE: Okay. This is a case of where we varied the owner's discount rate with a constant producer rate of ten percent in this case. And if you look, as you raise the discount rate, it lowers the price track, but it also does something else. You see, it does a steepening you would not see when you change the producer rate.

Now if you look at changes in the producer rate, you see it goes up and down, but it is a relative constant difference between the different prices.

MS. SHAPIRO: Right. No change in steepness, yes.

So by bringing them together, what have you done, flattened it?

MR. BRATHWAITE: Well, if you look at what --

MS. SHAPIRO: Or brought it closer?

MR. BRATHWAITE: If we did from what we did from before till now, we have done two things. Number one, we are lowering the producer rate, which should give a lowering of the price track.

MS. SHAPIRO: Right.

MR. BRATHWAITE: But we are also raising the owner's rate, which would lower -- yes, we should also lower the price track, but it should also give us a flattening because that's the effect it has in the model.

MS. SHAPIRO: Right. So it brings down the prices and flattens them?

MR. BRATHWAITE: Yes. It essentially does. That's right, yes.

MS. SHAPIRO: And we're pretty sure we are right this time? We have no idea?

MR. BRATHWAITE: Let me say this. There is no magic bullet here, because there is a lot of controversy. And, to tell you bluntly, these discounts rates have been a source of a lot of controversy in our office. Okay? Many times I have been like a lone wolf in the wilderness here.

But, as I said, this is no magic bullet. But we feel we are a little more right than we were before.

PRESIDING COMMISSIONER SHARPLESS: Now last year's or the last round, I should say, assumptions were based on the fact -- I mean, you didn't look at the certainty equivalent?

MR. BRATHWAITE: No, we did not.

PRESIDING COMMISSIONER SHARPLESS: That was missing out of that component?

MR. BRATHWAITE: Yes, Commissioner, that's exactly right.

PRESIDING COMMISSIONER SHARPLESS: The assumption was that there were different profiles and, therefore, we should adjust to the risk?

MR. BRATHWAITE: Exactly. Exactly.

PRESIDING COMMISSIONER SHARPLESS: And we went through some historical evaluation what those risk profiles

were and came up with the ratio --

MR. BRATHWAITE: Yes.

PRESIDING COMMISSIONER SHARPLESS: -- that we wound up using in our based assumption.

I know in reflecting, I went back through my files last week and drug out some of the old slides, Leon, so to compare. And we have been sort of all over the map on the discount rates from a basecase of six-six, which was equal.

MR. BRATHWAITE: Yes.

PRESIDING COMMISSIONER SHARPLESS: And I don't know how we came up with that equal if we didn't use an uncertainty equivalency to eight-eight to four-four to 3.5-3.5. It seems like we were using sort of equivalent ownership and producer. And from last year, I guess we got into the debate about whether or not we should split it.

So last year was sort of the deviation from the norm even though we were using a different theoretical set of assumptions when we used the same numbers for ownership and producers in the past; is that not right?

MR. BRATHWAITE: Yes. Well, the last time we had a contractor who made his presentation to the Committee about this very issue. And we did take his recommendations even though we did probably have some reservations about it, if I may be so blunt. But we did take his recommendation and did go to that 10 and four that we did eventually put into the

model.

After some serious discussion upstairs and some serious debate in the Office, we did feel we probably should move away from that difference in the risk profile and the difference in rates and go back to a rate that is equivalent and equal.

PRESIDING COMMISSIONER SHARPLESS: And basically your argument finally came down to the winning argument of equilibrium and market behavior?

MR. BRATHWAITE: Yes. Yes.

PRESIDING COMMISSIONER SHARPLESS: That's what it boils down to.

MR. BRATHWAITE: That's right, yes.

PRESIDING COMMISSIONER SHARPLESS: Is that assumption also used in other models by other organizations who do similar things? Are they using the same set of assumptions or are we coming up with our own unique set of assumptions?

MR. BRATHWAITE: Maybe Jairam can better answer that question than I can, Commissioner.

Jairam, do you know?

MR. GOPAL: Well, I think a discussion of our own participants indicates that it is probably better to go with this equal producer and owner discount rates. That was one.

Regarding the value, is it seven and a half, is it

nine. That I think varies from one agency to the other depending on how they view economic growth. Do they look at it from a national perspective or from a state perspective. So there are some differences.

PRESIDING COMMISSIONER SHARPLESS: Well, we are looking at it from a national, are we not?

MR. GOPAL: We are looking from a national perspective.

MR. BRATHWAITE: That's right, yes.

PRESIDING COMMISSIONER SHARPLESS: Who looks at it from the state perspective?

MR. GOPAL: I think if you want to just look at, say, some prices and do some economic analysis for just one state, you may want to focus more on the state economic growth.

PRESIDING COMMISSIONER SHARPLESS: I see. Well, I feel comfortable with the national perspective myself.

MR. GOPAL: Yes.

PRESIDING COMMISSIONER SHARPLESS: But I just wondered if somebody actually did that.

Scott?

MR. TOMASHEFSKY: I just wanted to add some clarification.

Last time what we did when we took our expert witness' advice, even though we had three different numbers,

two of them represented a combination of debt and equity and one was the producer rates.

So actually, if I recall correctly, the weighted average rate should have been equal to the producer and the owner rates. So the combination of debt and equity should have been equal to the producer rates. And I thought it was about four percent that we ended up with. It was like 10 for one, two and a half for the other and then four percent on the other side. And that combination of 10 and two and a half, depending on what type of debt equity ratio you come up, should give you about four percent.

PRESIDING COMMISSIONER SHARPLESS: So, in other words, in the past, we have tried to assemble our own basket rather than using the Standard and Poor's 500 basket and using that as a base point?

MR. TOMASHEFSKY: The model had six-six built into it from the day we bought it, and then we started looking at it about four years ago seriously to change it.

PRESIDING COMMISSIONER SHARPLESS: Okay.

MR. TOMASHEFSKY: That's when we had our expert witness then provide testimony. So we took the three components, debt equity and producer return. And those are the numbers we fed into the model for the last time.

So now we are looking at that again to see if we need to rework that, and Leon is suggesting we should. That will

be the basis for some more discussion that we have.

PRESIDING COMMISSIONER SHARPLESS: So we have an opportunity through this process for those who are heavily involved in this activity to challenge our assumptions and to debate those issues.

MR. BRATHWAITE: That's correct, yes.

PRESIDING COMMISSIONER SHARPLESS: Great. Well, I invite all to do so.

Are there any other questions or comments by those in the audience?

(No response.)

PRESIDING COMMISSIONER SHARPLESS: No.

MR. GOPAL: Commissioner, --

PRESIDING COMMISSIONER SHARPLESS: Yes.

MR. GOPAL: -- what we will be doing in this process is to take these recommended two values but also repeat the analysis with what we had in last year's forecast and then compare how it is going to change the projection trends.

PRESIDING COMMISSIONER SHARPLESS: Great. Thank you.

Thank you, Mr. Brathwaite.

MR. BRATHWAITE: Thank you very much, Commissioner.

PRESIDING COMMISSIONER SHARPLESS: Okay. We are now down to end-use price forecast issues.

MR. GOPAL: So I guess we will now shift from a

national perspective to a state perspective. Bill Wood will talk about the issues we need to consider in the end-use price forecast.

PRESIDING COMMISSIONER SHARPLESS: Great. Bill?

MR. WOOD: My name is Bill Wood. I work in the Fuels Office here at the Energy Commission. It is always great to see my name up in lights like that. It doesn't happen very often.

PRESIDING COMMISSIONER SHARPLESS: Ever so small.

MR. WOOD: Ever so small. Well, you notice I put it in fine type.

I'll be discussing today the assumptions and issues that are associated with my preparation of the end-use price forecast.

The first slide, I indicate there are four areas that have changed since our last forecast that we adopted last year. One of these areas is performance baserates. All utilities will now have access to these very shortly.

As we indicated earlier today, there are new pipeline proposals that are coming in to California. Socal Gas has filed a new biennial cost allocation to discover or to determine new allocations of their costs to the end-users.

And, finally, there are some issues with regard to contracting for interstate pipeline cap capacity that I would like to bring up.

Moving to the performance baserates. All the utilities in the past have had a form of this in place with regard to purchasing natural gas. They had indices that were oriented towards some sort of market basket of gas and then they had marks they had to make with regard to whether they lost or gained or broke even on the purchase of that gas.

During our last price forecasting, Socal Gas entered into the first of having performance baserates applicable to the nongas portion of their operational costs. And we incorporated that into the model.

In general, this kind of indices are applied to a base revenue requirement which sometimes is subject to a lot of argument amongst the different parties that are associated: What is my base cost going to be?

And then from that our escalation rates that are -- an escalation rate is then determined based upon several parameters. And I have listed these here. For the Socal BCAP it was the rate and change of inflation, the change in flow volumes with regard to individual use.

Then also there was this productivity index that was broken in two pieces. One was a historical measure the company measured and presented to the CPUC. And then additionally, there was this thing that was called the "stretch factor." That meant it forced the utility to be even more efficient than it is now in order to reap the benefits of

their operations. If they didn't stretch, if they didn't become more efficient, then they would lose money as a result.

At least based on these factors now, we can actually do our own, what we call, revenue requirement for a nongas cost. We have our own inflation costs. Our old inflation escalation rates. We also have our own information on our forecasts of what the volumes are going to be flowing into each of the utility systems. And working with the utility and with the CPUC, we will have to do something with the production index. We will gain something.

This is kind of the area of where there is a lot of discussion with regards to what should be included in a production index. And normally we look at what the decision was that developed that particular index and then work around that, because this index is generally good for about three to five years. We are looking for 20-year forecasts. So it is important we have that somewhat fixed in a logical form.

As I indicated earlier, Socal Gas has had this sort of performance baserate in place. They are moving into their second year now. And we will need to review to make sure our factors still are equivalent to what they are now using.

San Diego just received in December a decision from the CPUC, and I have received information from the CPUC on that decision -- or actually from San Diego for implementing that PBR. That is effective January 1st. So they are already

into it. So I will need to go back and look at that and get that incorporated into it.

Finally, PG&E had just recently filed an application to the CPUC to implement a PBR which would probably become effective, then, probably this time next year. We will look at that and see how is the best way to implement that into the analysis. This is going to be a little tricky at this point because we have not heard any of other discussion associated with this application. We will probably have to review and apply some of the stuff that we have learned from the Socal and San Diego and see how that fits in with the PG&E portion of it, so we can make a reasonable assumption of what the results will be from the CPUC decision.

Moving on. We have heard of the new pipeline proposals that are being presented to supply gas to Southern California. Ned Greenwood presented this morning earlier the Questar presentation. Again, they have purchased the Four Corners Pipeline that comes from San Juan Basin to Long Beach.

I was first introduced to this particular pipeline when I was working at the Air Resources Board many, many, many years ago. And we called it the mini SOHIO project when they reversed the flows on that particular pipe to move oil into the Texas area.

Their capacity, their indications are they can deliver approximately 120 million cubic feet a day into the

California area.

Kern River has also proposed building an extension into their existing system that would deliver approximately 300 million cubic feet per day into the Long Beach area. This would be new pipe. It wouldn't be old pipe. It's going to -- they are probably six months to a year away from filing anything to the FERC to get permission to go ahead in building this facility.

PRESIDING COMMISSIONER SHARPLESS: Excuse me, who did you say they were going to file with?

MR. WOOD: Kern River Pipeline.

PRESIDING COMMISSIONER SHARPLESS: Is going to file with whom, FERC?

MR. WOOD: With FERC, yes. With the FERC. So that is a ways away.

But Kern River has also done something with regards to its existing system that it has. It has offered some of its present shippers term discount rates that would allow them to reduce their present transportation costs in the area. Sixty five cents, if I remember.

Is that correct, Scott?

MR. TOMASHEFSKY: Who are you talking about?

MR. WOOD: The Kern River Pipeline current rates.

PRESIDING COMMISSIONER SHARPLESS: I think we have a person from Kern River that probably can answer that question.

MR. WOOD: It's about 65 cents; isn't it?

MR. BILLINGS: Our rate currently is 66 cents a decatherm and it is proposed to go down to 42 cents a decatherm.

PRESIDING COMMISSIONER SHARPLESS: And your name again was?

MR. BILLINGS: Kevin Billings.

PRESIDING COMMISSIONER SHARPLESS: Kevin Billings.

MR. WOOD: So in any event, there is this discounted operation. Discounted rates will allow this to drop earlier than it would normally have happened. It is still a few years away from when a drop would occur.

Additionally, Transwestern has just completed an open season to test the waters to see whether there is a desire for them to develop an additional 140 million cubic feet a day of delivery capacity to California. This would be at Topak. Needles actually, I guess, would be where it would be delivered to.

They are in the process now of evaluating that. All they would tell me was that it was successful, which kind of indicates they may be filing something with the FERC shortly. No new pipeline associated with this. It will all the compression additions. So it is a cheap way to add additional capacity into the state.

One area as we were just talking today came to mind

that I didn't include here, and that it is that Occidental Petroleum recently purchased Elk Hills. And through that operation, Occi has indicated they will probably be upping their production from the natural gas production -- or I shouldn't say they will be upping it. They will be releasing additional supplies from the Elk Hills for sale within the California area. This could be an additional several hundred million cubic feet per day. In fact, they might even -- that may also be based upon some additional production.

Currently, they have been releasing about 200 million cubic feet per day. And then the rest of their production has gone into for pressure maintenance in the oil production. But their analysis indicates it may be more beneficial at this point to release that gas and sell it into California.

So all of these things all pull --

PRESIDING COMMISSIONER SHARPLESS: They said rather than what?

MR. WOOD: Rather than put it into -- reinject it into the oil field --

PRESIDING COMMISSIONER SHARPLESS: Reinject it.

MR. WOOD: -- for pressure maintenance so it will produce more oil.

PRESIDING COMMISSIONER SHARPLESS: Does it have to anything to do with the oil prices?

MR. WOOD: Well, that could be it, too. But it also

could be they are in a cashflow problem where they bought this facility for a lot of money and now they have got to start paying it off. So it may be a combination of those things.

Altogether, though, all these new supply projects actually glean good for California in that they will provide more supply reliability to the state as well as more competition, particularly in Southern California, but some of this could spill over in the PG&E area also.

With regards to the Socal Gas BCAP application. A BCAP, or biennial cost allocation proceeding, allows the utility, after approval from the CPUC, to modify their rates and to reallocate the cost to the different customers with whom they deliver. And these we are talking about are the nongas costs. These are the operational costs within each of the utility systems.

Socal Gas recently filed their BCAP, and it looks like they will be looking for about a $200 million reduction. From what I have read, it indicates this could reduce the transmission cost for large noncore customers between 35 and 55 percent and impact the core customers by about a three-percent reduction in their transportation rates, so the nongas rates.

I reviewed our forecast we prepared from last year, and these reductions are pretty much in line with what we were forecasting that would occur in the year 2000. And that is

when these would, in essence, begin.

We see a forecast dropping for electric generation -- I'm sorry -- forecast for transporting gas in Socal Gas of about 52 cents dropping to around 27 cents, being in nominal dollars.

PRESIDING COMMISSIONER SHARPLESS: What is the basis for this drop again, Bill?

MR. WOOD: I was just going to get to that. That's my next point.

PRESIDING COMMISSIONER SHARPLESS: Oh, I'm sorry.

MR. WOOD: Our reduction was based upon two things that didn't have anything to do with the margin or the cost of operating the system. It actually had to do to surcharges that were ending. Our reductions were due to retiring of what is known as the PITCO-POPCO global settlement that went into effect several years ago. That's drawing to an end. They will no longer have to collect revenues for that.

In addition, we are forecasting a reduction in the interstate transportation cost surcharges that were levied on all customers within their system.

As you know, Socal Gas --

PRESIDING COMMISSIONER SHARPLESS: The surcharges are going off because why?

MR. WOOD: Because we are forecasting that the -- well, there are two things: One, Socal Gas is being relieved

of some of the firm capacity they now own. And we are also forecasting the transportation cost Socal is incurring will be reduced through fuller utilization of the Southwest Pipelines.

These transportation costs are due to Socal -- well, let's put it this way. Several years ago, Socal Gas entered into long-term contracts with El Paso and Transwestern to move firm pipeline capacity to move gas to California.

Subsequently to doing that, the CPUC relieved Socal Gas from the obligation of having to only serving the core market. They no longer had to serve the noncore market. Well, some of this firm capacity had been purchased in order to serve the noncore market.

Socal Gas still has to incur the cost of purchasing this firm capacity. And they then try to sell it on the side to the best they can. And what they don't sell they make up through allocating the revenue they don't recoup through sale or use of their own service through allocating those costs to the different end-users. That is what they call the ITCS service charge.

As the pipeline gets more utilized --

PRESIDING COMMISSIONER SHARPLESS: Then you can drop out the surcharges.

MR. WOOD: Then those things start dropping out or the discounts become less.

So under those circumstances then we have forecasted

those costs are dropping off.

I am going to be reviewing that application. I have requested a copy of it to see indeed was that what is really happening in their system.

PRESIDING COMMISSIONER SHARPLESS: What's the timing on that proceeding? Is that a real- --

MR. WOOD: They are supposed to be finished sometime next fall, I believe, with rates probably applicable either in the fall or the first of the year. Normally the CPUC runs a little bit late. So it may very well be we will see them about this time next year.

In any event, all of these things, Socal's application and its current status looks like they will provide rates that are very competitive with these new pipes that are being proposed for California.

Well, moving on. Contracting for interstate pipeline capacity. Here what I was throwing out is an issue that came up during the last forecast, and we kind of side-stepped it because it was only a three-year phenomena. That had to do with, first it was a natural gas clearing house purchased some capacity from El Paso. They were able to do that because PG&E had released their firm capacity on El Paso of about 1140 million cubic feet a day.

El Paso put that up for bid to see whether there would be any firm takers to take that firm capacity. And

nobody wanted to take the firm capacity. They were very happy to have this surplus, 1140 million cubic feet a day, sitting out there, because in essence that meant that gas, that transportation would probably be discounted. And so they could pick up this transportation on a nonfirm basis at very economical rates.

Well, Northern Gas or Natural Gas Clearing House saw the opportunity, given they have lots of customers within California as well as owning some power generation here, elected to pick up that 1140 million cubic feet at very favorable rates. And the net impact was about a 15-cent cost to them. About 12 or 13 cents was in fixed component, about two or three cents in commodity component, as I remember.

There were some stipulations associated with that. Not all of it was firm. Some of it was take-or-pay. In other words, they had to pay for it whether they used it or not. And those obligations shift with each year of the operation.

But the net effect of purchasing that was to set, in essence, a floor on the El Paso system of 15 cents. And actually a lot of the transactions have occurred at a higher price than that. That's another reason why Socal Gas has been able to potentially reduce some of their ITCS.

So what our question is that really arises at this point in time is: What is going to happen when that three-year period is over? It started in about the middle of

late 1997. So we have got three more years. So it will end around the middle, towards the end of the year 2000, I guess.

What is going to happen at that point, -- I left out a point here. Northern Gas Clearing House changed its name to Dynergy. I keep wanting to say Dynergy. I put an "r" in it, but there isn't. It's Dynegy.

And what's going to happen at that now, is that company going to reach contract for that capacity again? Reports are that from during the first year, it worked out very well for them. Or when that three year is up and El Paso puts that capacity on the board for bidding again, will shippers rush to have firm contracts so they can be more sure of what their transportation costs are going to be or is it going to be some sort of mix of those kinds of things happening or will it go back the way it was?

In this regard, and the other question of this is: Are there instances where this can occur elsewhere within the U.S., since our model operates on a U.S. basis? Are there other pipeline system where this phenomena could also occur?

And so one of the things we have to do then is look to see whether there are such areas. We'll have to do such --

PRESIDING COMMISSIONER SHARPLESS: Is that what you are going to try to do to answer those questions, is look for a similar situation?

MR. WOOD: Well, one of the things that happens is

-- one of the things we want to do first is to look to see whether there is that kind of a thing, a situation developed through the rest of the U.S.

But one of the interesting things that fell out of our last analysis was this may not be that important in five to six years from now. Because our analysis indicated the Southwest Pipeline system started getting utilized very heavily. It was almost approaching 70 to 80 percent of capacity. So, therefore, discounting, which is the real issue here, is discounting of the pipeline really going to occur?

PRESIDING COMMISSIONER SHARPLESS: Because demand is high, will discounting be part of the equation?

MR. WOOD: Right. Yes. So when demand is high on the pipe, that means the pipeline isn't going to be discounted as heavily. So, therefore, this issue of whether there is really going to be a lot of slack capacity in the Southwest system may not be that important with regards to analysis based upon the last forecast we did.

But, on the other hand, there is this other thing that is poking its head in, and that has to do with Questar and Kern River extending their system. So if those occur, it may relieve some of the pressure on the Southwest line. Though, listening to what Questar said today, they may be relying on El Paso Transwestern to deliver gas to them for further delivery into the Socal system, so that doesn't help

the system any with regards to alleviating some of the capacity needs we have on that El Paso Transwestern Northern system.

So it is going to be interesting to see how this shakes out in our analysis this time. Given what Mr. Greenwood said earlier today with regard to the multiple points they can deliver and receive gas, that is going to be an interesting modeling procedure for us to put into the model also.

So we are looking forward to seeing what kind of things shake out of this particular analysis this go-round. It is going to be fun I think.

PRESIDING COMMISSIONER SHARPLESS: Is any of the information they supplied to FERC helpful in answering some of these questions?

MR. WOOD: Yes. Well, we will be getting that information from them when they file and going through it and seeing what parts of it that --

PRESIDING COMMISSIONER SHARPLESS: And any conditions or other kinds of things that FERC places on them?

MR. WOOD: The restrictions aren't so important if we are talking in terms of environmental restrictions. We are more concerned about what the dollar costs are.

PRESIDING COMMISSIONER SHARPLESS: That is what I was referring to.

MR. WOOD: Yes. They are putting in for $158 million of costs. I ran a quick analysis on 40 million and that runs at around 15 cents. So if we take three times, four times that to get up to 158, it's 75. If we take the 35 and 35 and come up with a 75-cent transportation component, though, he didn't address that as being correct. He just said it's 35 cents and 35 cents. But if you run the numbers on 158, I think it will come out that the overall transportation cost is going to be 75 cents or better, to move it from one end of their pipe to the other.

So that is one of the things that we will be looking at, too.

PRESIDING COMMISSIONER SHARPLESS: Okay.

MR. WOOD: Bringing this altogether and -- oh, it's way past lunch time. I apologize for that.

A summary of our methodology at this point. Other than those areas I have indicated, we will probably have no real changes in our analysis.

PRESIDING COMMISSIONER SHARPLESS: Analysis methodology?

MR. WOOD: Yes, analysis methodology, right.

We don't see the natural gas strategy that is going on at the CPUC is going to offer anything for us. It is going to be after the year 2000 before we see anything there. And that may only affect the core area. We don't really see a lot

of change in the market sectors that we're going to be using -- preparing price forecasts. In fact, we are going to be using the same demand forecast as we used in the last forecast. That is the most recent one the Commission has put together.

PRESIDING COMMISSIONER SHARPLESS: Does disaggregation between electric generation and other industrial end-use, you don't see that having a major impact?

MR. WOOD: Well, we are not going to be making any changes in that area unless our Electricity Office has something to offer us with regards to a change in the demand for gas for generating electricity.

We will still be covering core residential, commercial-industrial, noncore commercial-industrial, TOR or enhanced oil recovery operations, cogeneration, electric generation. We are still going to be covering those.

And, like I say, unless the Electricity Office has a new forecast for us, we will be using this same forecast as we used in the last one. The res-commercial-industrial --

PRESIDING COMMISSIONER SHARPLESS: Is this forecast based on natural gas used by electric generation?

MR. WOOD: Yes. Yes.

And then, of course, based upon the BCAP filings that Socal Gas had and, actually, San Diego has also filed a BCAP filing in conjunction with that, we will go through and look

at reiterating and looking at how the costs are allocated, the nongas costs are allocated to the different end-use classes.

It is going to be a fun next six months pulling all this together. We are looking forward to that.

PRESIDING COMMISSIONER SHARPLESS: Right. Thank you very much, Mr. Wood.

Any questions?

Yes. Why don't you come forward and give your name and your affiliation?

MS. PAU: Hi. I'm Judy Pau of El Paso Natural Gas. And I just want to make a correction to Bill's presentation.

Our contract with Dynegy is a two-year contract --

MR. WOOD: Two?

MS. PAU: Yes. And it expires at the end of this year.

MR. WOOD: Okay.

MS. PAU: Just wanted to make a note of that.

MR. WOOD: Okay. Thank you.

PRESIDING COMMISSIONER SHARPLESS: Well, it means that your analysis is even more immediate than you thought.

MR. WOOD: Yes.

PRESIDING COMMISSIONER SHARPLESS: Are there any other questions or comments?

Additional information that anyone would like to provide that we haven't already heard? Different

perspectives?

(No response.)

PRESIDING COMMISSIONER SHARPLESS: Okay. Well, this isn't the last opportunity, obviously. This is sort of laying the foundation, as I indicated earlier in my comments, for the next round for the 1999 Natural Gas Forecast process. As the hearing note has indicated, there will be an opportunity if you wish to make additional comments, you can provide written comments.

We would ask you get those written comments into the Energy Commission's Docket Office by the close of business Wednesday, January 20th. That's not too far off. And we would ask you for our administrative and management purposes that you mention the Docket Number 99-FR, which stands for Fuels Report, -1 in your comments so that we can match it up.

And if there are no further comments, then I will adjourn today's proceeding and look forward to working with you all as we go through this process.

Thank you very much.

(Hearing adjourned at 12:26 p.m.)

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